CHAPTER III

PRELIMINARY CONCEPTUAL DESIGN OF COMMERCIAL GEOPRESSURED GEOTHERMAL FUEL PLANTS

A. INTRODUCTION

Previous feasibility studies Bechtel (1975), TRW (1975) for electric power generation utilizing geothermal resources have tended to focus primarily on the power plant and have neglected the fuel production and effluent disposal facilities. The Dow Chemical USA study (1974) for the Governor's Energy Advisory Council, State of Texas, placed equal emphasis on the power plant and the fuel plant. The study reported in Chapter II and in what follows in this chapter, also places equal emphasis on the two types of facilities.

It is important that the fuel plant, the well field, the fuel processing plant, and the effluent disposal facility be the subject of a preliminary conceptual design and costing activity so that economic and net energetics analysis can be performed. The activity also serves to assess technological maturity of the fuel plant and to identify technical problems requiring further study.

The resource considered was the model resource outlined in Section B, Chapter II. Fuel plants were outlined for three power generation plants: single-stage flash steam, two-stage flash steam, and propane secondary working fluid plant.

DISCLAIMER

B. PRELIMINARY CONCEPTUAL DESIGNS AND COST ESTIMATES

1. DESIGNS

Dow Chemical USA, Texas Division, Freeport, Texas prepared preliminary conceptual designs for fuel plants to supply fluids to a 25 MW(e) single-stage flash steam power plant and a 25 MW(e) two-stage flash steam power plant. The University of Texas used scaling laws and the Dow single-stage flash fuel plant to estimate the capital costs for a fuel plant for the Brown and Root propane secondary working fluid plant. The process for each fuel plant is the same; process and cost details of fuel plants for the two flash steam power plants are available in Appendix B of this volume. Estimated total costs (including additional wells for production maintenance) for a 13.4 well fuel plant for the propane secondary working fluid power plant are found in Table IV-4, Chapter IV.

The basic process is as follows: 14,000 foot deep wells produce geopressured geothermal fluids at the rate of 40,000 BBL/Day per well with wellhead conditions of 325°F and 2,000 psia. The fluids contain 40 SCF/BBL of methane, some of it in gas phase (about 49%) and the remainder still in-solution in the brine. A 2,000 psia separator removes the gas-phase methane; the 2,000 psia brine is then shipped across the "fence" to the power plant where a geohydraulic turbine produces shaft work while reducing the pressure to 300 psia. During the 1,700 psia pressure reduction in the geohydraulic turbine, methane comes out of solution. Thus a 300 psia separator is installed to remove this gas-phase methane (approximately 44% of total methane). For the flash steam power plant, a pressure reduction to 150 psia accompanied a second methane separator (approximately 8% of total methane). The last separator is necessary because methane, being a non-condensible, is undesireable in large quantities in the steam condenser. In a secondary working fluid power plant, the 300 psia brine would pass directly from the 300 psia separator to the secondary fluid vaporizers. After passing through the vaporizers, the 160°F, 240 psia brine will contain some gas phase methane; this methane can be separated immediately or the pressure could be dropped to 150 psia and then the methane separated. Assume that the latter is the case.

At this point, then, three methane/water vapor streams feed to the methane processing section of the fuel processing plant:

(a) 2,000 psia,~325°F stream with about 5% water by weight.

(b) 300 psia,~325°F stream with about 30% water by weight.

(c) 150 psia, 240-320°F stream with about 60% water by weight.

Pipeline quality methane should have a nominal pressure of 750 psia, have a temperature of 105°F, and be free of water vapor. The water vapor will have to be removed from each methane stream, each stream will require cooling, and the pressure of each stream must be appropriately adjusted.

Figures 7 and 8, Appendix B, illustrate the general methane processing flow chart. The 150 psia stream passes through an air cooler to drop the mixture temperature to somewhat below the temperature of saturated water at the water partial pressure. The water vapor then condenses into droplets; the droplets are removed in a separator. Methane from the separator passes through a compressor in which the pressure is increased to 300 psia. This 300 psia partially processed stream (c) is then mixed with the unprocessed 300 psia stream (b). The mixed stream is again partially processed by flowing through an air cooler, a water separator, and a compressor. This stream exits from the compressor at ~750 psia.

The 2,000 psia methane/water mixture passes through a pressure reduction station, the final pressure being ~750 psia. The two approximately 750 psia streams are mixed and then pass through an air cooler and a water separator. Remaining water vapor is removed from the combined stream using a glycol dehydrator. The final product is 750 psia, 105°F, pipeline quality gas containing less than 7 lb_m (less than 0.4%) entrained water vapor per thousand standard cubic feet.

The fuel plant for the Brown and Root, Inc., propane secondary working fluid plant deviates slightly from the Dow fuel plant designs. As the flow through the 2,000 psia separator is becoming very large for a 13.4 well fuel plant (535,000 BBL/Day), The University of Texas decided that instead of one 2,000 psia separator, two 267,500 BBL/Day separators operating in parallel were more appropriate. The cost for these was obtained by scaling downward from a 8.5 well separator to a 6.7 well separator using an 0.6 power law. The sizes of the reminder of methane processing plant were linearly scaled upward from 10.8 wells to 13.4 wells and the component costs were scaled upward using an 0.6 power law. Well field costs were scaled linearly while the gathering system was costed again for those larger components (piping, etc.) which replace smaller components and to include extra components.

The Dow process design does not include thermal recovery in place of the air coolers or thermal recovery from the compressors. The process does not include energy recovery using an expander in place of the standard pressure reduction station. With respect to the latter, the expander would be expected to operate at about 65,000 RPM, requiring approximately a 20:1 gear reduction train to match the rotational speeds of the proposed reciprocating compressors. The maximum theoretical shaft horsepower available from the pressure reduction ranges from 120 HP to 190 HP, depending upon fuel plant size. Considerably less (60 - 80%) can actually be recovered. Theoretical maximum thermal recovery from the methane (without compressor recovery) ranges from 3.5×10^6 to 5.6×10^6 Btu/hr; this translates into approximately 3,000 to 4,600 lb_m/hr of 300^0F, 66 psia steam. Considerably less than this amount of thermal recovery is possible. However, if 50% recovery were possible and if a 70% efficient turbine utilized the steam, shaft work ranging from 480 to 750 SHP would be available to run the methane compressors. These fuel plants, therefore, have the potential for recovering from 550 to 860 SHP depending upon the plant (8.5, 10.8, or 13.4 wells production), independent of compressor recovery. In order to determine the economic and energetic feasibility of recovery, a trade-off study which compares the following would be necessary:

(1) Recovery system capital investment, operation, and maintenance costs.

versus

(2) Electric motor drive capital and power costs.

2. COST ESTIMATES

Fuel plant cost estimates for initial costs are presented in Table III-1 for the two-flash steam plants and the secondary working fluid plant. These estimates differ from those of Table II-3 because the fuel plant costs stated there include the additional estimates for continued well drilling to maintain well field production. The initial installed costs for each fuel

TABLE III-1

ESTIMATED INITIAL INVESTMENT COMPARISONS FOR VARIOUS FUEL PLANTS [$\$10^3$]

COMPONENT/PLANT	SINGLE-STAGE FLASH [25MW(e)]	TWO-STAGE FLASH [25MW(e)]	SECONDARY FLUID [33MW(e)]
A. Source Wells	23,103	19,253	28,880
B. Reinjection Wells			
1. Coverted Dry Source	8,245	6,956	11,543
2. New Reinjection	11,400	9,000	13,200
C. Gathering/Disposal System			
1. Piping	2,379	1,909	3,300
2. Reinjection Well Pumps	376	452	703
D. Methane Processing System			
1. Air Coolers	46	40	62
2. Mehtane Compressors	1,257	990	1,540
3. Water Separators	75	65	101
4. High Pressure (2,000 psia) Separator	5,416	4,708	8,098
5. Glycol Dehydrator	125	109	170
6. Particulates Filter	5	4	6
E. Site Development	439	425	613
TOTAL FUEL PLANT	53,067	43,551	68,216
INSTALLED CAPACITY:			
($/kW)	2,183	1,792	2,018
($/$10^3$ SCF)	3,114	3,190	3,136

plant are broken down into subcategories (source wells, reinjection wells, gathering/disposal system, methane processing system, and site development). Installed costs are also presented in terms of initial installed cost per net kilowatt in the power plant and per thousand standard cubic feet methane production capacity.

3. TECHNICAL MATURITY

Design of each component in the typical geopressured geothermal fuel plant is based upon a wealth of oil and/or gas field experience. The only component for which assumptions were necessary because of lack of field experience was the high pressure methane separator. For that component, the brine flow rates are much higher, relative to the methane flow rates, than usually encountered in field practice. However, chemical process and refinery process experience provides a reasonable set of guidelines for design.

REFERENCES

Bechtel Corporation, May 1975, Electric power generation using geothermal brine resources for a proof-of-concept facility: ERDA, AER 74-19931 A01.

Dow Chemical Company, 1974, An analysis of the potential use of geothermal energy for power generation along the Texas Gulf Coast: prepared for the Governor's Energy Advisory Council, Texas.

TRW Systems Group, December 31, 1974, Experimental geothermal research facilities study (Phase 0), Volumes I and II, Final report number: 26405-6601-RU-00.